CHAPTER ONE

INTRODUCTION

1.1 Overview

In the past several decades, there has been a rapid growth in the power grid all over the world which eventually led to the installation of a huge number of new transmission and distribution lines. Moreover, the introduction of new marketing concepts such as deregulation has increased the need for reliable and uninterrupted supply of electric power to the end users who are very sensitive to power outages. One of the most important t factors that hinder the continuous supply of electricity and power is occurrence of a faults in the power system. Hence, it is very important to have a well-coordinated protection system that detects any kind of abnormal flow of current in the power system, identifies the type of fault and then accurately locates the position of the fault in the power system.

The faults are usually taken care of by devices that detect the occurrence of a fault and eventually isolate the faulted section from the rest of the power system. Hence some of the important challenges for the incessant supply of power are detection, classification and location of faults. Faults can be of various types namely transient, persistent, symmetric or asymmetric faults and the fault detection process for each of these faults is distinctly unique in the sense, there is no one universal fault location technique for all these kinds of faults.

In recent years, the vast enterprise of supplying electrical energy presents many engineering problems which provided the engineers with a variety of challenges. The entire design must be predicated on automatic control and not on the slow response of human operations which has made it possible to design and construct economic and reliable power systems capable of satisfying the continuity growth in demand for electrical energy. In this, power system protection and control play a significant part, and progress in design and development in these fields has necessarily had to keep pace with advances in the design of primary plant, such as transformers, switchgears, and overhead lines.

The problem of combining fast fault clearance with selective tripping of plant is a key aim for the protection of power systems. To meet these requirements, high-speed protection systems for transmission and primary distribution circuits that are suitable for use with the automatic enclosure of circuit breakers are under continuous development and are very widely applied.

Distance protection, in its basic form, is a non-unit system of protection offering considerable economic and technical advantages. Unlike phase and neutral overcurrent protection, the key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations [1].

The kilovolt standards for high voltage transmission lines used in Sudan electrical network are 500KV,220KVand 110KV.The generation consists of hydro generation which is far away from the load center and thermal generation which is concentrated in the load center which is surrounded by 220KVand 110KV transmission lines known as Khartoum rings. The Blue Nile transmission line connect Roseries hydro power station with the load center throw 220KV transmission line. The 500KV transmission line connect Merowe hydro power station with the load center.

1.2 Problem Statement

Occurrence of faults in power systems leads to large damages. It interrupts the operation of the power system, deteriorates the reliability of the system, and causes power system components damage. The heavy currents result in the excessive heating of lines, cables and winding resulting in fire or explosion. Also, Stability of the system may be adversely affected, cascade tripping of power system components may take place, and complete blackout may occur. If the fault is not cleared quickly arc on over-head transmission lines may burn the conductors causing it to break resulting in long time interruption of the supply. If the fault detected mistakenly the fault will not clear and the above problem still unsolved so it is important to know the type and zone of the fault to be cleared correct. There are many problems faced the fault classification methods. As in impedance method the fault detection is slow and the results are inaccurate. Mistaken fault report sent to control centers or directly fed to protection systems may deteriorate the problem. It may cause tripping healthy parts and leaving behind faulty parts.

1.3 Objectives

The main objectives to:

i. Detection of fault location in transmission line.
ii. Maintain continuity supply to grid.
iii. Improve the power system reliability.
iv. Increase the sensitivity of protection system.
v. Obtain full information about the faults.
vi. Obtain Correct operation of the distance relay in all zones.

1.4 Methodology

Several stages were taken in order to ensure that the desired objectives of the project were achieved. The first stage of this project; necessary data of transmission line between MASHKOR and JEBAL AWLIA The second stage; CT and VT ratio were selected, and then the setting was calculated according to IEEE and IEC standards. The third stage; numeric relays from and using MATLAB2014a in the field of protection were used in order to obtain full and advanced protection of the transmission line.

1.5 Project Layout

In chapter one introduction. In chapter two represent the literature review of protection system, types of faults, and relays technology. In chapter three the present distance protection, and distance relays and their characteristics. The numerical relay, its application at distance protection, and the results are present in chapter four. at chapter five present the conclusions and recommendations.

CHAPTER TWO

LITERATURE REVIEW

2.1 Electric Power System

An electric power system refers to a network that constitutes electrical components/machines used in the generation, transmission and consumption of electric power [2]. The diagram below illustrates a complete electric power system. It involves generation, transmission and distribution of electric power to various categories of consumers. The generation plant is normally located far from the load center. There are different levels of electric power consumption depending on the purpose for which a consumer uses electricity. Electrical power consumers may be industrial, commercial or domestic. These consumers require different levels of electric power supply. In order to meet their specific needs, certain devices that adjust the voltage levels accordingly have to be used. Some of those components include: step up and step down transformers, capacitor banks, protective devices etc [3]. The purpose of the electric transmission system is the interconnection of the electric-energy-producing power plants or generating stations with the loads. A three-phase AC system is used for most transmission lines [4]. It is shown in Figure 2.1.

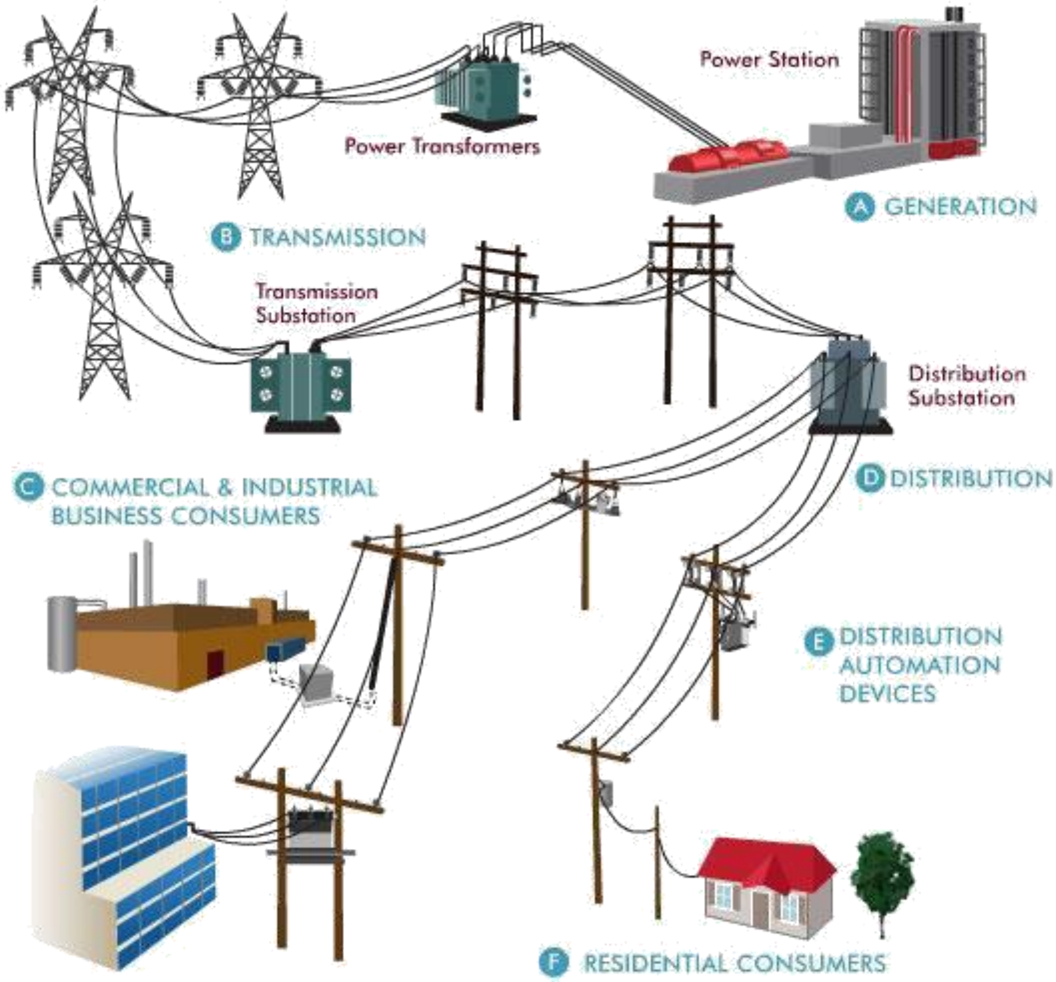


Figure 2.1: Generation, transmission and distribution of electrical power.

2.2 Nature and Causes of Faults

Faults are caused by insulation failures or by conducting path failures. Most of faults in transmission line caused by overvoltage due to lightning, switching surge or external faults (trees, birds, snow, windy…etc.).

2.2.1 Types of faults

They are three types of fault such as:

i. Symmetrical faults; (Is a three-phase short-circuited with ground or without ground).

ii. Unsymmetrical faults;(LG, LLG, LL, and open circuit).

iii. Simultaneous faults;(The same or different types of faults occurring at the same or different point of the line).

2.2.2 Effect of faults

The most dangerous type of fault is short-circuiting. It has effects to power system if it remains uncleared :

i. Heavy current causes damage.
ii. Arcs cause fire hazards.
iii. Reduce in the supply voltage.
iv. Unbalance supply voltage and current effected to load (machine).
v. Loess of system stability.
vi. It causes an interruption of supply to consumers, thereby causing a loss of revenue.

50% of total faults occur on overhead lines hence it is overload lines that required more attention while planning and design protective schemes for power system. The cost of protective equipment generally works out to be about 5% of the total cost of the system[4].

2.3 Power System Protection

A branch of electrical power engineering that deals with protection of Power system from faults is known as power system protection. It does this by isolating the faulted parts of the system from the rest of healthy electrical network [5]. The diagram below shows a model of a power protection system. It is shown in Figure 2.2.

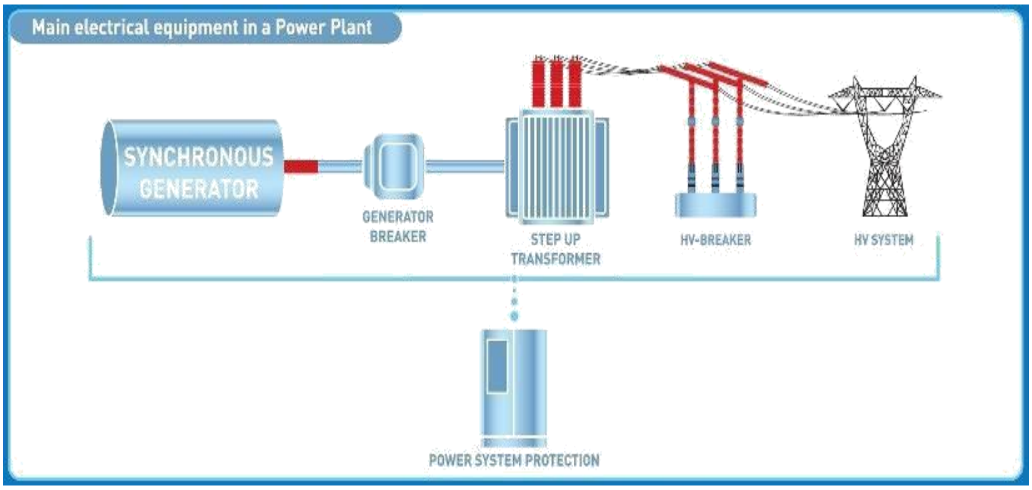


Figure 2.2: power system protection

The main aim of power system protection scheme is to switch off a section that is faulty in the system from the remaining live system. This ensures that the remaining portion is able to function satisfactorily locking out chances of damage that may be caused by fault current.

A circuit breaker closes automatically as a result of trip signals it receives from the relay whenever a fault is detected. The basic philosophy of a power protection system is that system faults cannot be prevented from flowing in the system but can be stopped from spreading in the system.

2.3.1 Importance of power system protection

Occurrence of fault is hazardous to both electric power user and the electric system itself. To the user, life is of most important concern. The main concern of the system is to ensure a stable supply of electric power to consumer and to ensure that the electrical components do not get destroyed. In summary, power protection is necessary to:

i. User/Personnel- ensure safety i.e. prevent injury/accident.
ii. Electrical equipment - to protect the equipment from cases of over current, overvoltage and frequency drift that can destroy the equipment.
iii. General safety -prevent secondary accidents that occur as a result of system fault like fire.

iv. Power supply stability- Ensures a continuous and stable supply of electrical power.
v. Operation cost -Ensure optimal operating efficiency so as to reduce equipment maintenance/replacement cost.

2.3.2 Protective zones

A protective zone is the separate zone which around each system element. The significance of such a protective zone is that any fault occurring within a given zone will cause the tripping of relays which cause opening of all circuit breakers located within that zone. As shown in Figure 2.3.

The boundaries of protective zones are decided by the location of the current and voltage transformers. In practice, various protective zones are overlapped. The overlapping of protective zones is done to ensure complete safety of each and every element of the system, otherwise there could be some portion which is left out and remains unprotected [6].

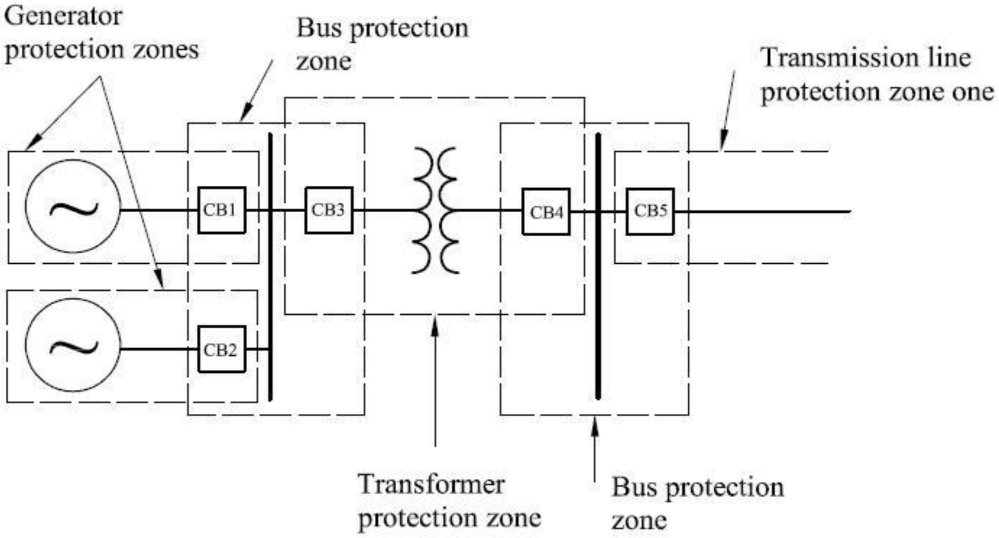


Figure 2.3: Protection zones marked

2.3.3 Types of protection systems

Implementation of power system protection can be done in two ways. These are: the unit protection and non-unit protection, OR main and backup protection [2].

i. Unit Protection:

The unit protection scheme protects a definite\discrete zone bounded by the protection system. Differential relay protection is normally employed in this scheme. It is shown in Figure 2.4.

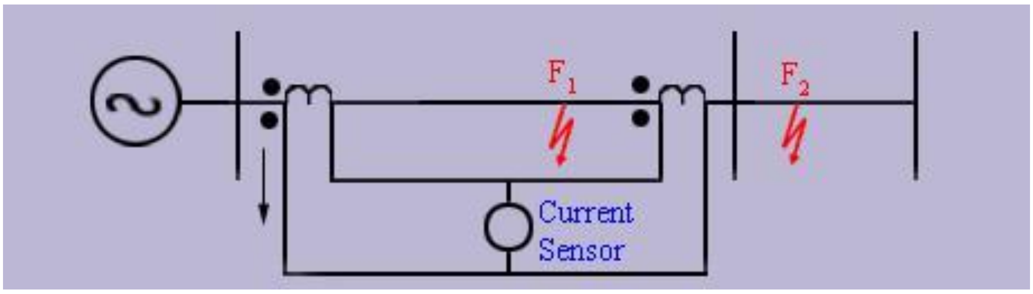


Figure 2.4: Unit protection.

ii. Non-Unit protection:

The Non-Unit protection protects a system\zone and can overlap with another protection zone in the system. This scheme ensures an isolation of the entire circuit (a larger area) in case a fault occurs as illustrated in figure below, It is shown in Figure 2.5.

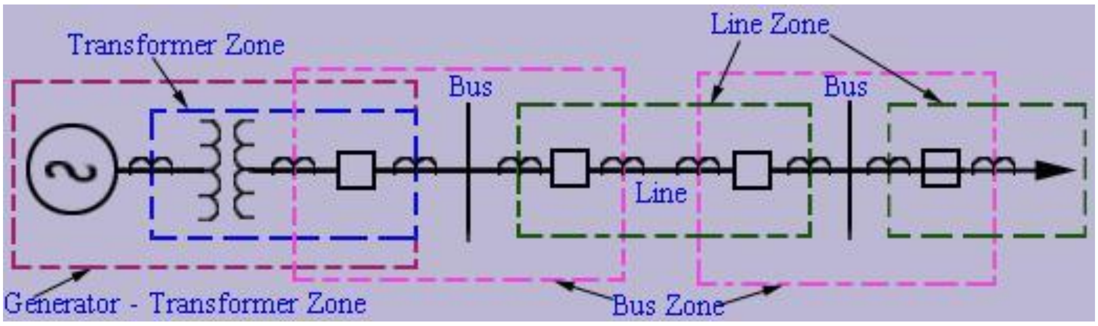


Figure 2.5: Non-unit protection

iii. Primary Protection or Main Protection:

The primary protection is the first line of defense and is responsible to protect all the power system elements from all types of faults[6].

iv. Back-up Protection:

As already mentioned there are times when the primary protection may fail. This could due to failure of the CT/VT or relay, or failure of the circuit breaker. One of the possible causes of the circuit breaker failure is the failure of the trip battery due to inadequate maintenance. We must have a second line of defense in such a situation. Therefore, it is a normal practice to provide another zone of protection which should operate and isolate the faulty element in case the primary protection fails. A little thought will convince the reader that the back-up protection should not have anything in common with the primary protection. It should also preferably be located at a place different from where the primary protection is located. Further, the back-up protection must wait for the primary protection to operate, before issuing the trip command to its associated circuit breakers. In other words, the operating time of the back-up protection must be delayed by an appropriate amount over that of the primary protection. Thus, the operating time of the back-up protection should be equal to the operating time of primary protection plus the operating time of the primary circuit breaker [5].

2.3.4 Power protection elements

There are four types of these elements, namely instrument transformers, switchgears, protective gears and station batteries.

i. Instrument Transformers: these include current transformers and voltage transformers. Instrument transformers step down current and voltage from the power line to level that can be measured safely.

ii. Switchgears: switchgears basically include circuit breakers. Circuit breakers are the main part of a protection system. They break contacts of the system in case of a fault. They include minimum oil, bulk oil, SF6, vacuum and air blast circuit breakers. Mechanisms of operation of circuit breakers include: hydraulic, solenoid, spring and pneumatic[2].

iii. Protective Gear: consists of protective relays like voltage, current, impedance, frequency and power relays, based on operating parameter, definite time, inverse time, and stepped relays, classified according to operating characteristic, differential and over fluxing relays classified according to logic. When a fault occurs, relay sends signal to relay to the circuit breaker completing its circuit thus making it to trip [2].

iv. Station Batteries: all circuit breakers in a power system operate using direct current. The current is provided by battery banks that are installed together with the circuit breaker. It is thus an essential element in a power protection system. It is shown in Figure 2.6.

Figure 2.6: Station battery.

2.3.5 Functional requirement of protection relay

In order for a protection relay to operate effectively, it must have the following qualities:

i. Reliability: power protection relays should remain inoperative always as long as a fault does not occur. But when a fault occurs, they should respond as quickly as possible.

ii. Selectivity: it must only operate on the section that has experienced a fault to avoid unnecessary power outs due to wrong detections. It should also respond only when a fault occurs.

iii. Sensitivity: The relaying equipment should be highly sensitive so that it can be relied on to provide the required detection.

iv. Speed: the relaying equipment must operate at the required speed. It should not delay so as to give time for system equipment to get destroyed. It should also not be too fast to cause undesired operation.

v. Stability: Stable to the external fault condition or the fault occur outside the zone protected.

vi. Adequateness: The protective system must provide adequate protection for any element of the system. the adequateness of the system can be assessed by considering following factors:

   a. Rating of various equipment.
   b. Cost of the equipment.
   c. Location of the equipment.
   d. Probability of abnormal condition due to internal and external causes.
   e. Discontinuity of supply due to the failure of the equipment.

vii. Simplicity and economy: The protective system should be as simple as possible so that it can be easily maintained. The protection cost should not be more than 5% of the total cost. But if the equipments to be protected are very important, the economic constraints can be relaxed [7].

2.4 Protective Relay

Relaying is the branch of electric power engineering concerned with the principles of design and operation of equipment (called ‘relays’ or ‘protective relays’) that detects abnormal power system conditions and initiates corrective action as quickly as possible in order to return the power system to its normal state. The quickness of response is an essential element of protective relaying systems – response times of the order of a few milliseconds are often required. Consequently, human intervention in the protection system operation is not possible. The response must be automatic, quick and should cause a minimum amount of disruption to the power system [8].

The last thirty years have seen enormous changes in relay technology. The electromechanical relay in all of its different forms has been replaced successively by static, digital and numerical relays, each change bringing with it reductions and size and improvements in functionality. At the same time, reliability levels have been maintained or even improved and availability significantly increased due to techniques not available with older relay types. This represents a tremendous achievement for all those involved in relay design and manufacture [9].

2.4.1 Electromechanical relays

These relays were the earliest forms of relay used for the protection of power systems, and they date back around 100 years. They work on the principle of a mechanical force operating a relay contact in response to a stimulus. The mechanical force is generated through current flow in one or more windings on a magnetic core or cores, hence the term electromechanical relay. The main advantage of such relays is that they provide galvanic isolation between the inputs and outputs in a simple, cheap and reliable form. Therefore, these relays are still used for simple on/off switching functions where the output contacts carry substantial currents. It is shown in Figure2.7.

Figure 2.7: Attracted armature relay.

Electromechanical relays can be classified into several different types as follows:

i. attracted armature.
ii. moving coil.
iii. induction.
iv. thermal.
v. motor operated.
vi. mechanical.

However, only attracted armature types have significant application at this time, all other types having been superseded by more modern equivalents. It has limited because the moving parts required repeating maintenance[1].

2.4.2 Static relays

The expansion and growing complexity of modern power systems have brought a need for protective relays with a higher level of performance and more sophisticated characteristics. This has been made possible by the development of semiconductors and other associated components which can be utilized in relay designs, generally referred to as solid-state or static relays. In a protection relay, the term ‘static’ refers to the absence of moving parts to create the relay characteristic [1, 8].

Early versions used discrete devices such as transistors and diodes in conjunction with resistors, capacitors, inductors, etc., they can be viewed in simple terms as an analogue electronic replacement for electromechanical relays, with some additional flexibility in settings and some saving in space requirements. A number of design problems had to be solved in static relays. In particular, the relays generally require a reliable source of D.C power and measures to prevent damage to vulnerable electric circuits had to be devised. this type used have limited it is more sensitive to temperature and voltage transients [9]. It is shown in Figure 2.8.

Figure 2.8: types of static relays.

2.4.3 Digital relays

Digital protection relays introduced a step change in technology. Microprocessors and microcontrollers replaced analogue circuits used in static relays to implement relay functions. Early examples began to be introduced into service around 1980, and, with improvements in processing capacity, can still be regarded as current technology for many relay applications. However, such technology will be completely superseded within the next five years by numerical relays.

Compared to static relays, digital relays introduce A/D conversion of all measured analogue quantities and use a microprocessor to implement the protection algorithm. The microprocessor may use some kind of counting technique or use the Discrete Fourier Transform (DFT) to implement the algorithm. However, the typical microprocessors used have limited processing capacity and memory compared to that provided in numerical relays. The functionality tends therefore to be limited and restricted largely to the protection function itself. Additional functionality compared to that provided by an electromechanical or static relay is usually available, typically taking the form of a wider range of settings, and greater accuracy. A communications link to a remote computer may also be provided.

The limited power of the microprocessors used in digital relays restrict the number of samples of the waveform that can be measured per cycle. This, in turn, limits the speed of operation of the relay in certain applications. Therefore, a digital relay for a particular protection function may have a longer operation time than the static relay equivalent [1]. It is shown in Figure 2.9.

Figure 2.9: types of digital relays.

2.4.4 Numerical relays

The distinction between digital and numerical relay rests on points of fine technical detail, and is rarely found in areas other than Protection. They can be viewed as natural developments of digital relays as a result of advances in technology. It is shown in Figure(2.10) Typically, they use a specialized digital signal processor (DSP) as the computational hardware, together with the associated software tools.

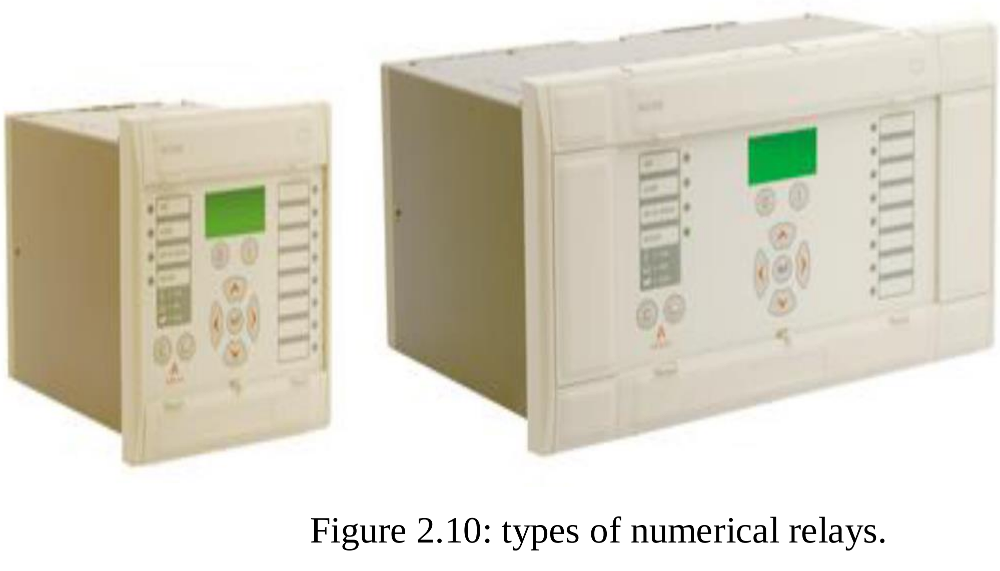


Figure 2.10: types of numerical relays.

CHAPTER THREE

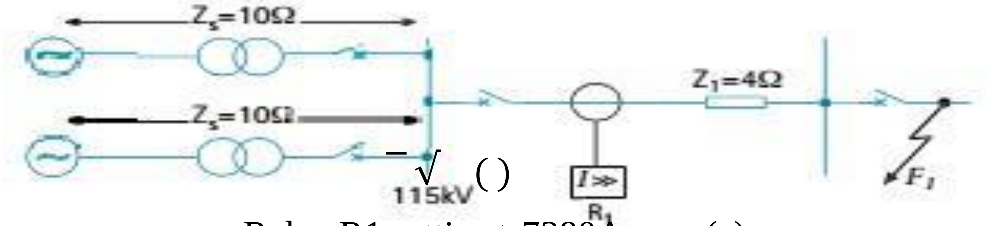
DISTANCE PROTECTION

3.1 Introduction

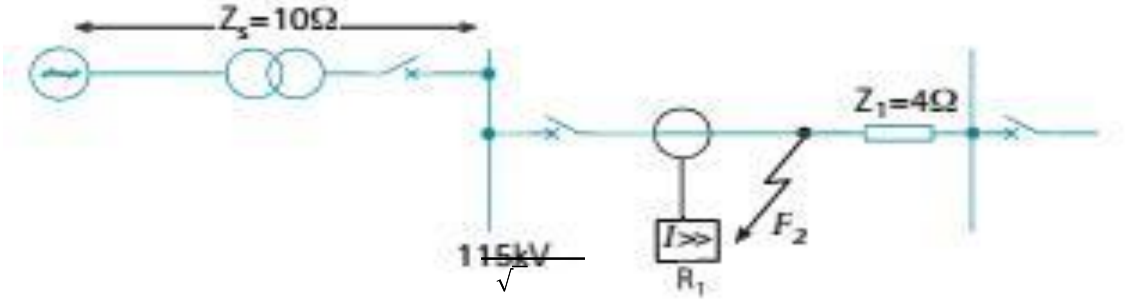
Overcurrent relays, which were quite adequate protective devices for radial circuits, are not generally capable of being properly coordinated for meshed transmission systems. Because of this inadequacy of overcurrent relays, other types of relays have been devised that are more selective and that have performance features that make them more applicable to the needs of high voltage transmission circuits. Distance relays are often a first choice for replacing overcurrent relays when the overcurrent relays are found to be inadequate for an application [10].

Distance protection provides short-circuit protection for universal application. It provides the basis for network protection in transmission systems and meshed distribution systems. While classic distance protection, based on electro mechanical or static technology, are still in wide use, the state of the art today are multi-functional micro-processor devices. They communicate with centralized control systems and may be operated with personal computers locally or from remote. The basic operating principles of distance protection also apply to the new technology. Numerical signal processing, and intelligent evaluation algorithms facilitate measuring techniques with increased accuracy and protection functions with improved selectivity [11].

The problem of combining fast fault clearance with selective tripping of plant is a key aim for the protection of power systems. To meet these requirements, high speed protection systems for transmission and primary distribution circuits that are suitable for use with the automatic reclosure of circuit breakers are under continuous development and are very widely applied. Distance protection, in its basic form, is a non-unit system of protection offering considerable economic and technical advantages. Unlike phase and neutral overcurrent protection, the key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations.



Relay R1 setting >7380A (a)



(b)

Therefore, for relay operation for line fault,

Relay current setting <6640A and >7380A

This is impractical, overcurrent relay not suitable. Must use Distance or Unit protection

Figure 3.1: Advantages of distance over overcurrent protection.

This is illustrated in Figure 3.1, where it can be seen that overcurrent protection cannot be applied satisfactorily. Distance protection is comparatively simple to apply and it can be fast in operation for faults located along most of a protected circuit. It can also provide both primary and remote back-up functions in a single scheme. It can easily be adapted to create a unit protection scheme when applied with a signaling channel. In this form it is eminently suitable for application with high-speed auto reclosing, for the protection of critical transmission lines[1].

3.2 Principle of Distance Relays

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point (the reach point). Such a relay is described as a distance relay and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur in different line sections. The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point. The reach point of a relay is the point along the line impedance locus that is intersected by the boundary characteristic of the relay. Since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an R/X diagram. The loci of power system impedances as seen by the relay during faults, power swings and load variations may be plotted on the same diagram and in this manner the performance of the relay in the presence of system faults and disturbances may be studied [1].

3.3 Relay Performance

Distance relay performance is defined in terms of reach accuracy and operating time. Reach accuracy is a comparison of the actual ohmic reach of the relay under practical conditions with the relay setting value in ohms. Reach accuracy particularly depends on the level of voltage presented to the relay under fault conditions. The impedance measuring techniques employed in particular relay designs also have an impact. Operating times can vary with fault current, with fault position relative to the relay setting, and with the point on the voltage wave at which the fault occurs. Depending on the measuring techniques employed in a particular relay design, measuring signal transient errors, such as those produced by Capacitor Voltage Transformers or saturating CT’s, can also adversely delay relay operation for faults close to the reach point. It is usual for electromechanical and static distance relays to claim both maximum and minimum operating times. However, for modern digital or numerical distance relays, the variation between these is small over a wide range of system operating conditions and fault positions [1].

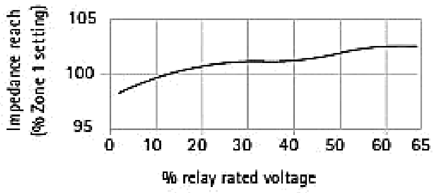
3.3.1 Electromechanical/static distance relays

With electromechanical and earlier static relay designs, the magnitude of input quantities particularly influenced both reach accuracy and operating time. It was customary to present information on relay performance by voltage/reach curves, as shown in Figure 3.2, and operating time/fault position curves for various values of system impedance ratios (S.I.R.’s) as shown in Figure 3.3, where:

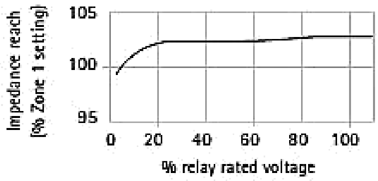
$$— \qquad 3.1$$

and

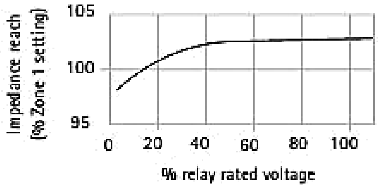
ZS = system source impedance behind the relay location.
ZL = line impedance equivalent to relay reach setting.



(a) Phase-earth faults

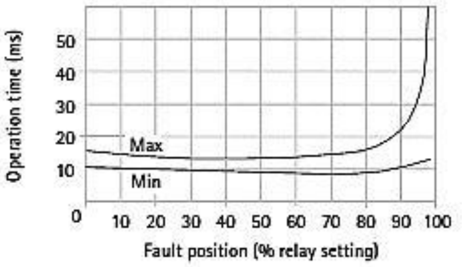


(b) Phase-phase faults

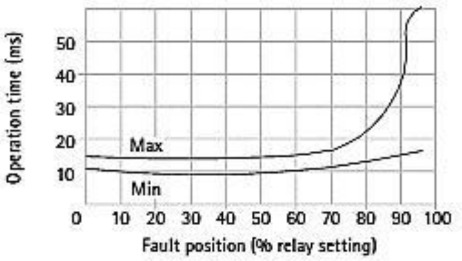


(c) Three-phase and three-phase-earth faults

Fig.3.2: Typical of impedance reach accuracy characteristics for zone 1.

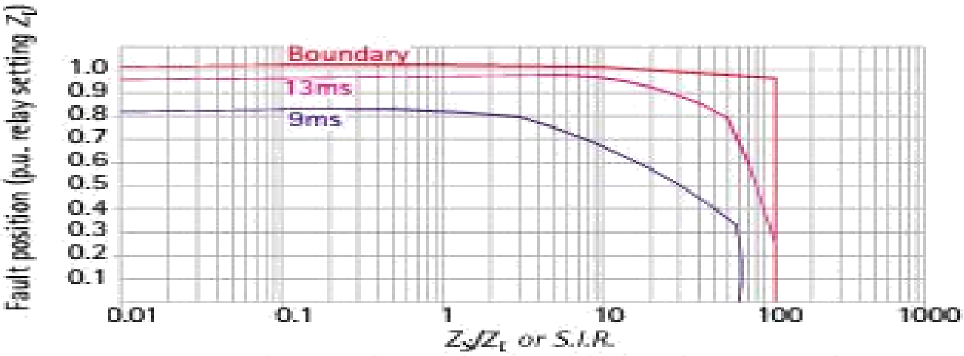


(a) With system impedance ratio of 1/1

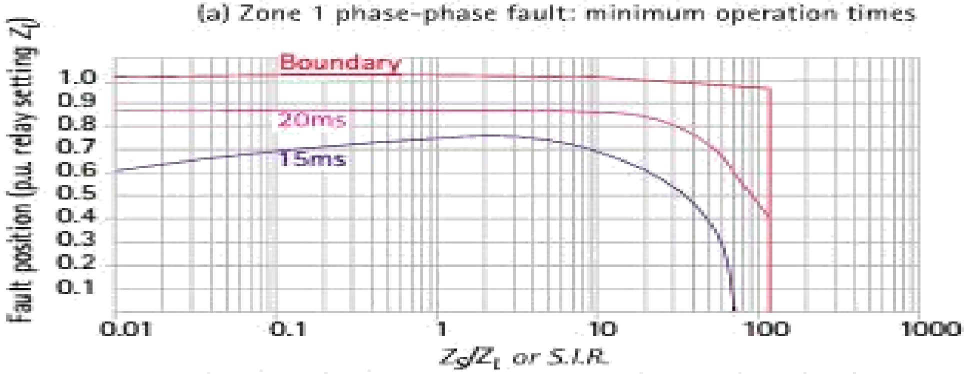


(b) With system impedance ratio of 30/1

Figure 3.3: Typical operation time characteristics for Zone 1 phase-phase faults. Alternatively, the above information was combined in a family of contour curves, where the fault position expressed as a percentage of the relay setting is plotted against the source to line impedance ratio, as illustrated in Figure 3.4.



(a) Zone 1 phase-phase fault: minimum operation times



(b) Zone 1 phase-phase fault: maximum operation times

Figure 3.4: Typical operation-time contours

3.3.2 Digital/Numerical distance relays

Digital/Numerical distance relays tend to have more consistent operating times. They are usually slightly slower than some of the older relay designs when operating under the best conditions, but their maximum operating times are also less under adverse waveform conditions or for boundary fault conditions [1].

3.4 Zones of Protection

Careful selection of the reach settings and tripping times for the various zones of measurement enables correct coordination between distance relays on a power system.

Basic distance protection will comprise instantaneous directional Zone 1 protection and one or more-time delayed zones. Typical reach and time settings for a 3- zone distance protection are shown in Figure 3.5. Digital and numerical distance relays may have up to five zones, some set to measure in the reverse direction. Typical settings for three forward-looking zones of basic distance protection are given in the following sub-sections. To determine the settings for a particular relay design or for a particular distance teleprotection scheme, involving end-to-end signalling, the relay manufacturer's instructions should be referred to [1].

3.4.1 Zone 1 setting

Electromechanical/static relays usually have a reach setting of up to 80% of the protected line impedance for instantaneous zone 1 protection. For digital/numerical distance relays, settings of up to 85% may be safe. The resulting 15-20% safety margin ensures that there is no risk of the Zone 1 protection over-reaching the protected line due to errors in the current and voltage transformers, in accuracies in line impedance data provided for setting purposes and errors of relay setting and measurement. Otherwise, there would be a loss of discrimination with fast operating protection on the following line section. Zone 2 of the distance protection must cover the remaining 15-20% of the line [1].

3.4.2 Zone 2 setting

Ensure full cover of the line with allowance for the sources of error already listed in the previous section, the reach setting of the Zone 2 protection should be at least 120% of the protected line impedance. In many applications it is common practice to set the Zone 2 reach to be equal to the protected line section +50% of the shortest adjacent line. Where possible, this ensures that the resulting maximum effective Zone 2 reach does not extend beyond the minimum effective Zone 1 reach of the adjacent line protection. This avoids the need to grade the Zone 2 time settings between upstream and downstream relays. In electromechanical and static relays, Zone 2 protection is provided either by separate elements or by extending the reach of the Zone 1 elements after a time delay that is initiated by a fault detector. In most digital and numerical relays, the Zone 2 elements are implemented in software. Zone 2 tripping must be time-delayed to ensure grading with the primary relaying applied to adjacent circuits that fall within the Zone 2 reach. Thus complete coverage of a line section is obtained, with fast clearance of faults in the first 80-85% of the line and somewhat slower clearance of faults in the remaining section of the line [1]. All zones shown in Figure 3.5

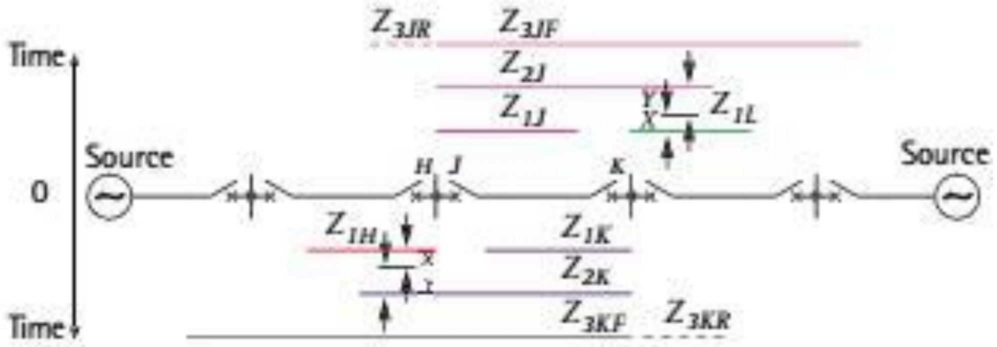


Figure 3.5: Typical time/distance characteristics for three zone distance protection.

Zone 1 = 80-85% of protected line impedance

Zone 2 (minimum) = 120% of protected line

Zone 2 (maximum) <protected line + 50% of shortest second line

Zone 3F =1.2 (protected line +longest second line)

Zone 3R = 20% of protected line

X = Circuit Breaker tripping time

Y = Discriminating time

3.4.3 Zone 3 setting

Remote back-up protection for all faults on adjacent lines can be provided by a third zone of protection that is time delayed to discriminate with Zone 2 protection plus circuit breaker trip time for the adjacent line. Zone 3 reach should be set to at least 1.2 times the impedance presented to the relay for a fault at the remote end of the second line section. On interconnected power systems, the effect of fault current infeed at the remote busbars will cause the impedance presented to the relay to be much greater than the actual impedance to the fault and this needs to be taken into account when setting Zone 3. In some systems, variations in the remote busbar infeed can prevent the application of remote back-up Zone 3 protection but on radial distribution systems with single end infeed, no difficulties should arise [1].

3.4.4 Settings for reverse reach and other zones

Modern digital or numerical relays may have additional impedance zones that can be utilized to provide additional protection functions. For example, where the first three zones are set as above, Zone 4 might be used to provide back-up protection for the local busbar, by applying a reverse reach setting of the order of 25% of the Zone 1 reach. Alternatively, one of the forward-looking zones (typically Zone 3) could be set with a small reverse offset reach from the origin of the R/X diagram, in addition to its forward reach setting. An offset impedance measurement characteristic is non-directional. One advantage of a non-directional zone of impedance measurement is that it is able to operate for a close-up, zero-impedance fault, in situations where there may be no healthy phase voltage signal or memory voltage signal available to allow operation of a directional impedance zone. With the offset-zone time delay bypassed, there can be provision of ‘Switch-on-to Fault’ (SOTF) protection. This is required where there are line voltage transformers, to provide fast tripping in the event of accidental line energization with maintenance earthing clamps left in position. Additional impedance zones may be deployed as part of a distance protection scheme used in conjunction with a teleprotection signaling channel [1].

3.5 Distance relay characteristics

Some numerical relays measure the absolute fault impedance and then determine whether operation is required according to impedance boundaries defined on the R/X diagram. Traditional distance relays and numerical relays that emulate the impedance elements of traditional relays do not measure absolute impedance.

They compare the measured fault voltage with a replica voltage derived from the fault current and the zone impedance setting to determine whether the fault is within zone or out-of-zone. Distance relay impedance comparators or algorithms which emulate traditional comparators are classified according to their polar characteristics, the number of signal inputs they have, and the method by which signal comparisons are made. The common types compare either the relative amplitude or phase of two input quantities to obtain operating characteristics that are either straight lines or circles when plotted on an R/X diagram. At each stage of distance relay design evolution, the development of impedance operating characteristic shapes and sophistication has been governed by the technology available and the acceptable cost. Since many traditional relays are still in service and since some numerical relays emulate the techniques of the traditional relays, a brief review of impedance comparators is justified [1].

3.5.1 Amplitude and phase comparison

Relay measuring elements whose functionality is based on the comparison of two independent quantities are essentially either amplitude or phase comparators. For the impedance elements of a distance relay, the quantities being compared are the voltage and current measured by the relay. There are numerous techniques available for performing the comparison, depending on the technology used. Any type of impedance characteristic obtainable with one comparator is also obtainable with the other. As shown in Figure 3.6 The addition and subtraction of the signals for one type of comparator produces the required signals to obtain a similar characteristic using the other type. For example, comparing V and I in an amplitude comparator results in a circular impedance characteristic centered at the origin of the R/X diagram. If the sum and difference of V and I are applied to the phase comparator the result is a similar characteristic [1].

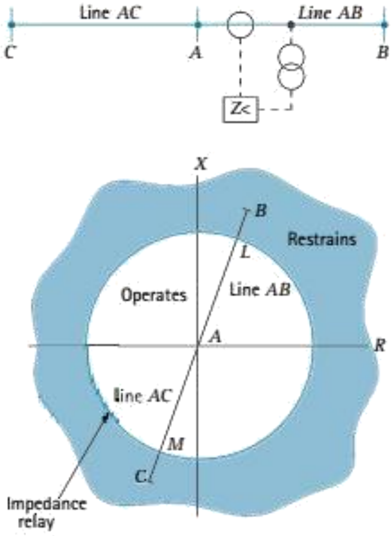


Figure 3.6: Plain impedance relay characteristic.

3.5.2 Plain impedance relay characteristic

As shown in Figure 3.8,this characteristic takes no account of the phase angle between the current and the voltage applied to it; for this reason, its impedance characteristic when plotted on an R/X diagram is a circle with its center at the origin of the co-ordinates and of radius equal to its setting in ohms. Operation occurs for all impedance values less than the setting, that is, for all points within the circle. The relay characteristic, shown in Figure 3.6, is therefore non-directional, and in this form would operate for all faults along the vector AL and also for all faults behind the busbars up to an impedance AM.

The impedance relay work corresponding to the ratio of voltage V and current I of the circuit to be protected. There are two elements in this relay, the one produce a torque proportional to current (operating torque –positive torque) while the other produce a torque proportional to voltage (restraining torque-negative torque) [3].

When the fault occurs at point F in the protected zone then the voltage drops while current increases. Thus, the ratio V/I i.e. the impedance reduces drastically than it's predetermined value Z_L it trips and makes the circuit breaker open. As shown in Figure 3.7 below:

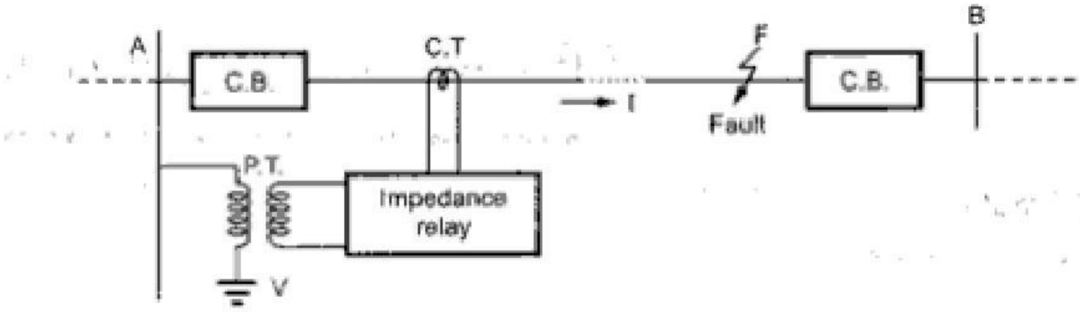
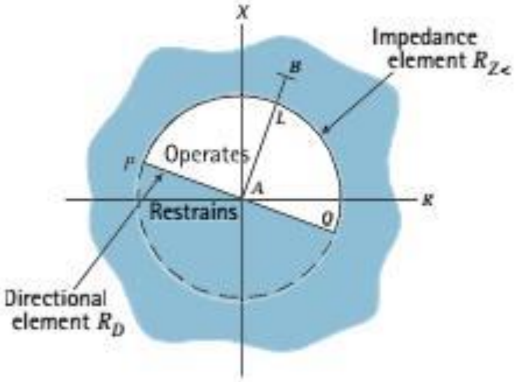
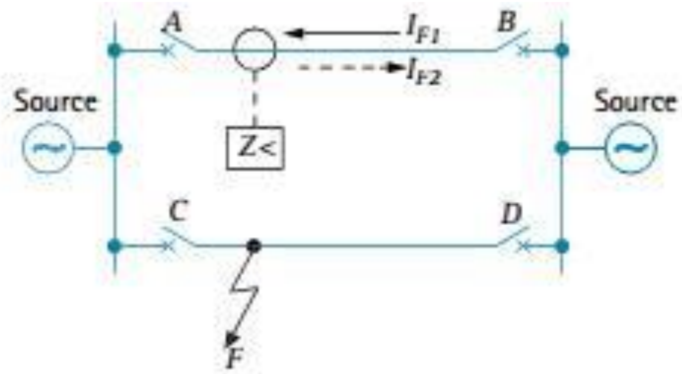


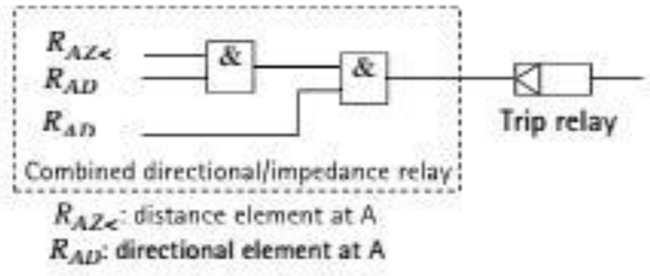
Figure 3.7:Basic operation of impedance relay.



(a) Characteristic of combined directional/impedance relay



(b) Illustration of use of directional/impedance circuit diagram



(c) Logic for directional and impedance elements at A

Figure 3.8: Combined directional and impedance relays.

A relay using this characteristic has three important disadvantages:

1. it is non-directional; it will see faults both in front of and behind the relaying point, and therefore requires a directional element to give it correct discrimination.
2. it has non-uniform fault resistance coverage.
3. it is susceptible to power swings and heavy loading of a long line, because of the large area covered by the impedance circle Directional control is an essential discrimination quality for a distance relay, to make the relay non-responsive to faults outside the protected line. This can be obtained by the addition of a separate directional control element.

3.5.3 Directional impedance relay

The directional impedance relay can be obtained by adding a directional element in the basic impedance relay. The element can sense the direction of power or current flow and relay can operate only if the direction of power flow is in one particular direction with respect to the point where relay is installed. The impedance characteristic of a directional control element is a straight line on the R/X diagram, so the combined characteristic of the directional and impedance relays is the semi-circle APLQ shown in Figure3.8.

By applying additional voltage to the voltage coils of an impedance relay, the torque equation of the relay can be modified, the additional voltage supplied is proportional to the line current and is called current bias. The modified torque equation is [6]

$$T=K_1 I^2 - K_2 (V+K_3 I)^2 \qquad (3.2)$$

where $(v+k_3 I)$ = voltage supplied to the voltage

coil T= Torque (N.M).

V=Voltage(V).

I= current(A)

K_1, K_2= constant

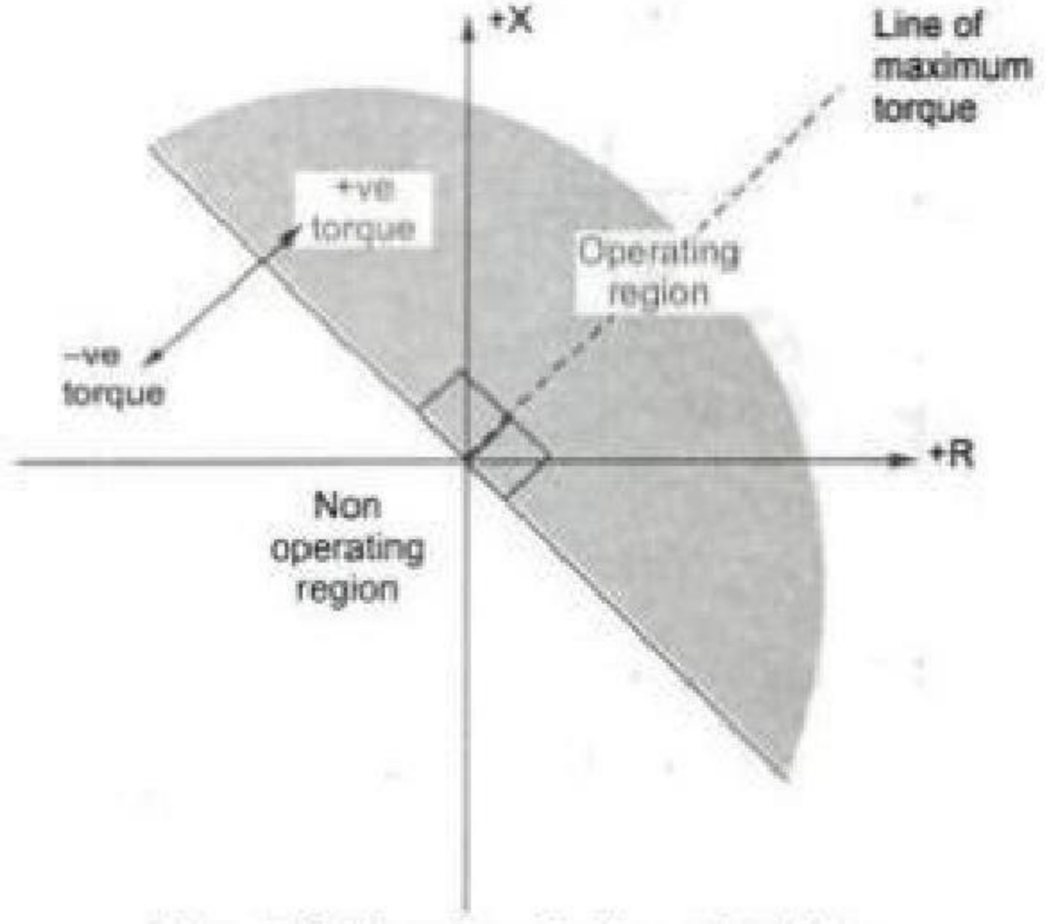


Figure 3.9: Directional Characteristics.

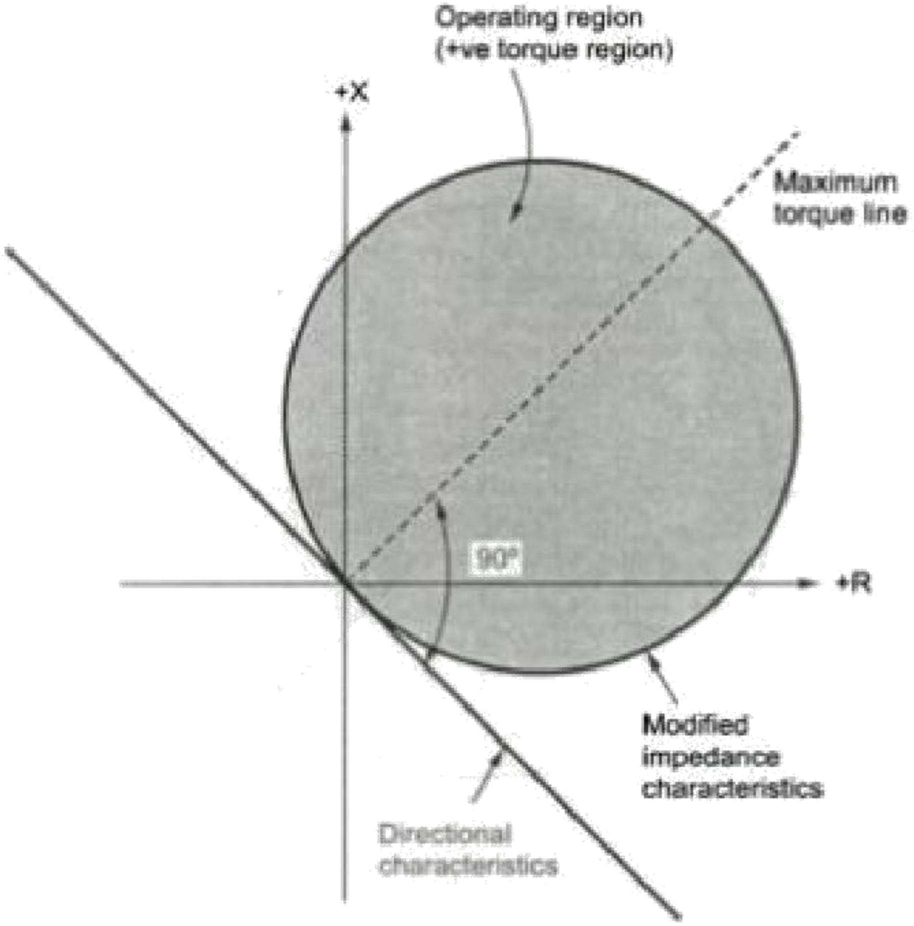


Fig.3.10: Modified directional impedance relay characteristics.

3.5.4 Reactance relay

In this relay the operating torque is obtained by current while the restraining torque due to a current-voltage directional relay. The overcurrent element develops the positive torque and directional unit produce negative torque. Thus, the reactance relay is an overcurrent relay with the directional restraint. The directional element is so designed that maximum torque angle is 90^{o}.This relay is a non-directional relay also the relay will operate even under normal load conditions if the system is operating at or near unity power factor condition as shown in Figure 3.11. The reactance relay with directional feature is called mho relay or admittance relay [6].

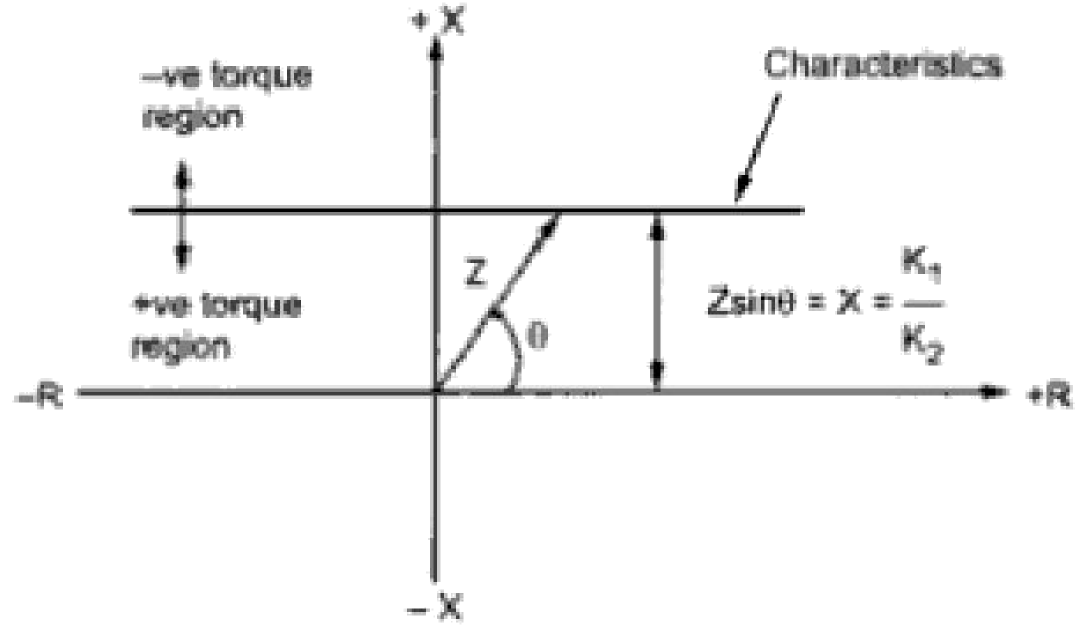
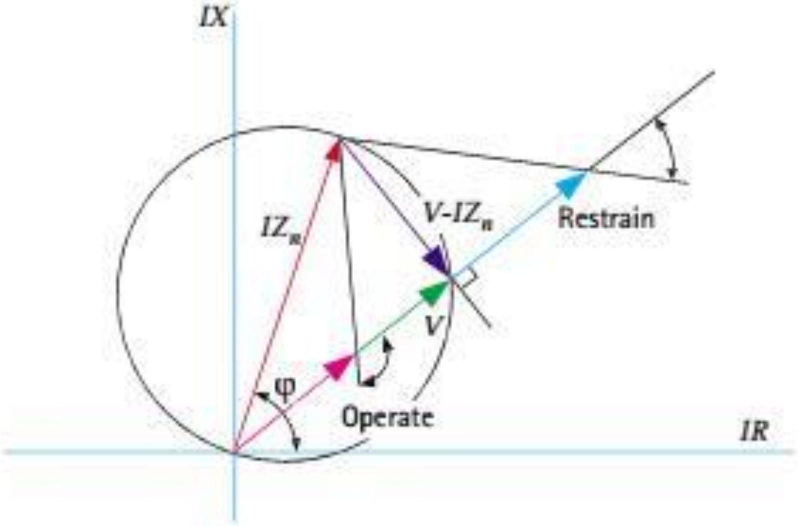


Figure 3.11: Operating characteristics of reactance relay.

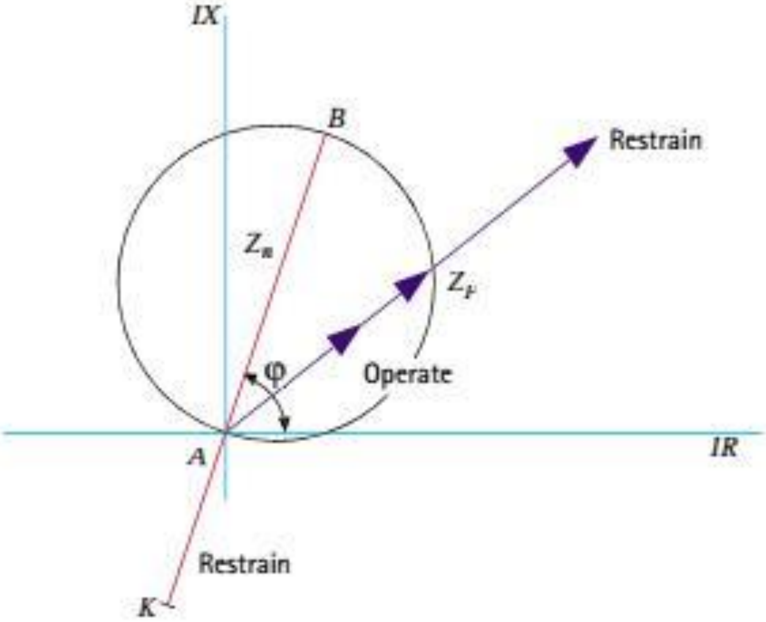
3.5.5 Mho Relay

In the impedance relay a separate unit required to make it directional while the same unit can not be used to make a reactance relay with directional feature. The mho relay is made inherently directional by adding a voltage winding called polarizing winding. The relay works on the measurement of admittance Y. This relay is also called angle impedance relay [6].

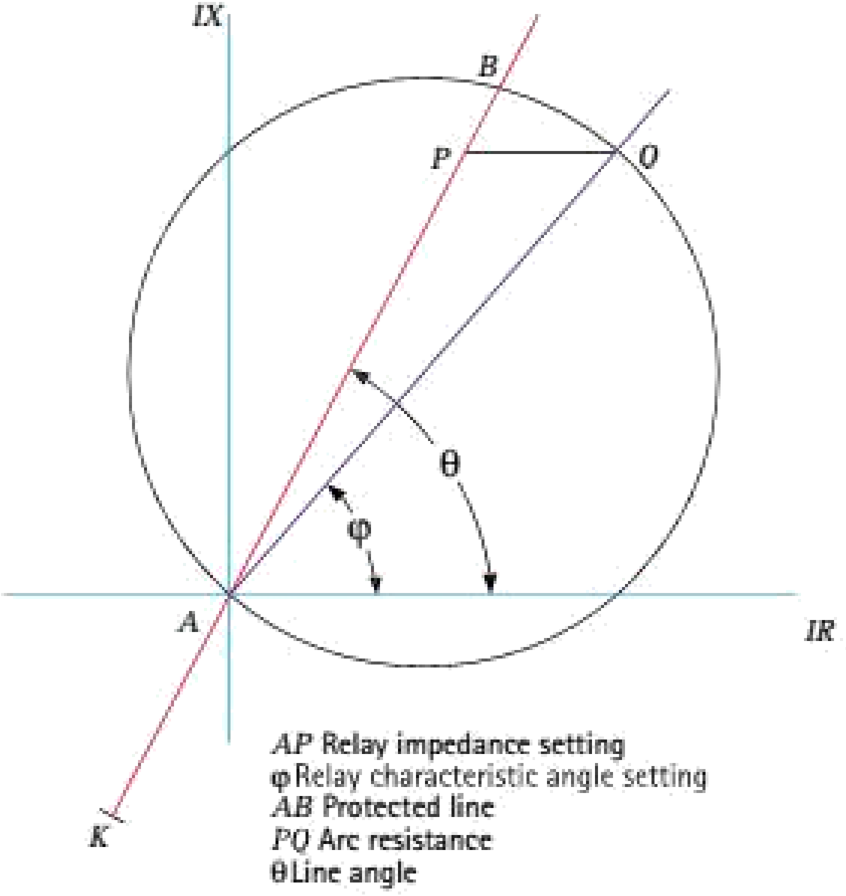
The mho impedance element is generally known as such because it characteristic is a straight line on an admittance diagram. It cleverly combines the discriminating qualities of both reach control and directional control, thereby eliminating the ‘contact race’ problems that may be encountered with separate reach and directional control elements. This is achieved by the addition of a polarizing signal. Mho impedance elements were particularly attractive for economic reasons where electromechanical relay elements were employed. As a result, they have been widely deployed worldwide for many years and their advantages and limitations are now well understood. For this reason, they are still emulated in the algorithms of some modern numerical relays. The characteristic of a mho impedance element, when plotted on an R/X diagram, is a circle whose circumference passes through the origin, as illustrated in Figure 3.8(b). This demonstrates that the impedance element is inherently directional and such that it will operate only for faults in the forward direction along line AB. As shown in Figure 3.12.



(a)Phase compartor inputs



(b)Mho impedance characteristic



(c)Increased arc resistance coverage

Figure 3.12: Mho relay characteristic.

The impedance characteristic is adjusted by setting Zn, the impedance reach, along the diameter and ϕ, the angle of displacement of the diameter from the R axis. Angle ϕ is known as the Relay Characteristic Angle (RCA). The relay operates for values of fault impedance ZF within its characteristic.

It will be noted that the impedance reach varies with fault angle. As the line to be protected is made up of resistance and inductance, its fault angle will be dependent upon the relative values of R and X at the system operating frequency. Under an arcing fault condition, or an earth fault involving additional resistance, such as tower footing resistance or fault through vegetation, the value of the resistive component of fault impedance will increase to change the impedance angle. Thus, a relay having a characteristic angle equivalent to the line angle will under-reach under resistive fault conditions. It is usual, therefore, to set the RCA less than the line angle, so that it is possible to accept a small amount of fault resistance without causing under-reach. However, when setting the relay, the difference between the line angle and the relay characteristic angle ϕ must be known. The resulting characteristic is shown in Figure 3.12(c) where AB corresponds to the length of the line to be protected. With ϕ set less than , the actual amount of line protected, AB, would be equal to the relay setting value AQ multiplied by cosine (-ϕ). Therefore, the required relay setting AQ is given by:

$$\frac{\qquad}{(\qquad)} \tag{3.3}$$

Due to the physical nature of an arc, there is a non-linear relationship between arc voltage and arc current, which results in a non-linear resistance. Using the empirical formula derived by A.R. van C. Warrington, [3.1] the approximate value of arc resistance can be assessed as:

$$\frac{\qquad}{\qquad} \tag{3.4}$$

where:

Ra = arc resistance (ohms)
L = length of arc (meters)
I = arc current (A)

On long overhead lines carried on steel towers with overhead earth wires the effect of arc resistance can usually be neglected. The effect is most significant on short overhead lines and with fault currents below 2000A (i.e. minimum plant condition), or if the protected line is of wood-pole construction without earth wires. In the latter case, the earth fault resistance reduces the effective earth-fault reach of a mho Zone 1 element to such an extent that the majority of faults are detected in Zone 2 time. This problem can usually be overcome by using a relay with a cross-polarized mho or a polygonal characteristic.

Where a power system is resistance-earthed, it should be appreciated that this does not need to be considered with regard to the relay settings other than the effect that reduced fault current may have on the value of arc resistance seen. The earthing resistance is in the source behind the relay and only modifies the source angle and source to line impedance ratio for earth faults. It would therefore be taken into account only when assessing relay performance in terms of system impedance ratio [1].

3.5.6 Quadrilateral characteristic

This form of polygonal impedance characteristic is shown in Figure 3.13. The characteristic is provided with forward reach and resistive reach settings that are independently adjustable. It therefore provides better resistive coverage than any mho-type characteristic for short lines. This is especially true for earth fault impedance measurement, where the arc resistances and fault resistance to earth contribute to the highest values of fault resistance. To avoid excessive errors in the zone, reach accuracy, it is common to impose a maximum resistive reach in terms of the zone impedance reach.

Recommendations in this respect can usually be found in the appropriate relay manuals.

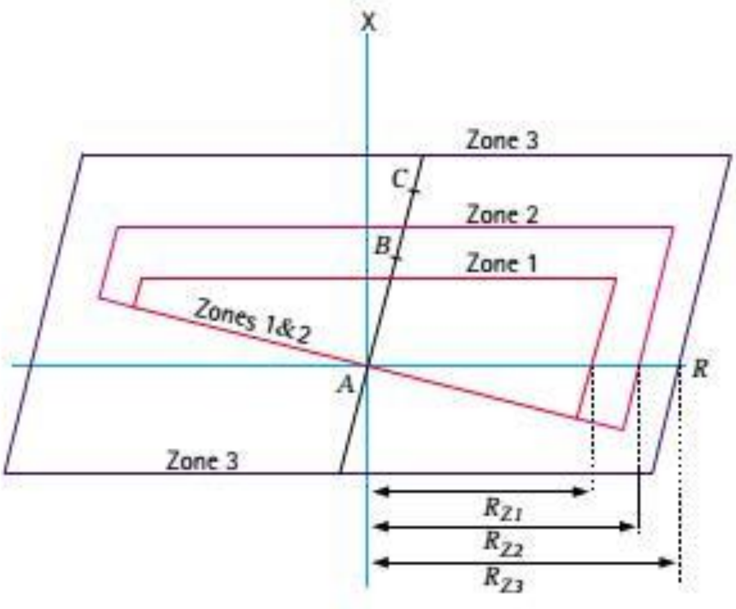


Figure 3.13: Quadrilateral characteristic.

Quadrilateral elements with plain reactance reach lines can introduce reach error problems for resistive earth faults where the angle of total fault current differs from the angle of the current measured by the relay. This will be the case where the local and remote source voltage vectors are phase shifted with respect to each other due to pre-fault power flow. This can be overcome by selecting an alternative to use of a phase current for polarization of the reactance reach line. Polygonal impedance characteristics are highly flexible in terms of fault impedance coverage for both phase and earth faults. For this reason, most digital and numerical distance relays now offer this form of characteristic. A further factor is that the additional cost implications of implementing this characteristic using discrete component electromechanical or early static relay technology do not arise [1].

3.6 Auto-Reclosing

Faults on overhead lines fall into one of three categories:

i. transient
ii. semi-permanent
iii. permanent

80-90% of faults on any overhead line network are transient in nature. The remaining 10%-20% of faults are either semi-permanent or permanent. Transient faults are commonly caused by lightning or temporary contact with foreign objects, and immediate tripping of one or more circuit breakers clears the fault. Subsequent re-energization of the line is usually successful.

Use of an auto-reclose scheme to re-energize the line after a fault trip permits successful re-energizations of the line. Sufficient time must be allowed after tripping for the fault arc to de-energize before reclosing otherwise the arc will re-strike. Such schemes have been the cause of a substantial improvement in continuity of supply. A further benefit, particularly to HV systems, is the maintenance of system stability and synchronism.

Instantaneous tripping reduces the duration of the power arc resulting from an overhead line fault to a minimum. The chance of permanent damage occurring to the line is reduced.

The application of instantaneous protection may result in nonselective tripping of a number of circuit breakers and an ensuing loss of supply to a number of healthy sections. Auto reclosing allows these circuit breakers to be reclosed within a few seconds. With transient faults, the overall effect would be loss of supply for a very short time but affecting a larger number of consumers.

When instantaneous protection is used with auto-reclosing, the scheme is normally arranged to inhibit the instantaneous protection after the first trip. For a permanent fault, the time graded protection will give discriminative tripping after reclosure, resulting in the isolation of the faulted section. Some schemes allow a number of reclosures and time-graded trips after the first instantaneous trip, which may result in the burning out and clearance of semi-permanent faults. A further benefit of instantaneous tripping is a reduction in circuit breaker maintenance by reducing pre-arc heating when clearing transient faults [1].

3.7 Auto-Reclosing on HV Transmission Lines

The most important consideration in the application of auto-reclosing to HV transmission lines is the maintenance of system stability and synchronism. The problems involved are dependent on whether the transmission system is weak or strong. With a weak system, loss of a transmission link may lead quickly to an excessive phase angle across the circuit breaker (CB) used for reclosure, thus preventing a successful re-closure. In a relatively strong system, the rate of change of phase angle will be slow, so that delayed auto-reclose can be successfully applied [1].

3.8 Fault Detection Techniques

Conventional fault detection algorithms are designed based on current or voltage magnitude measurements. Increase of current magnitude or decrease of voltage/impedance magnitude could be considered as a measure to detect a system fault. These algorithms are dependent on various factors such as fault resistance and power system short circuit capacity. Current based starters get confused when load current is significant compared to fault current. Conventional over current based starters may not be able to detect faults with high amount of fault resistance.

For remote low current faults, no clear under voltage condition arises at the relay location. In the case of a close-in fault on a weak system, all voltages deviate from the nominal value. Therefore, the voltage based starters might not be able to perform correctly for different fault conditions. For the conventional based fault detectors, current and voltage magnitudes should be estimated correctly using appropriate filtering algorithms. When a fault happens on a transmission line, the power system goes through a transient period. It might not be easy to determine current/voltage signal magnitude fast and precisely during the transient period after the occurrence of the fault. As power systems grow both in size and complexity, it becomes necessary to identify different system faults faster and more accurately using more powerful algorithms. It would be desirable to design a reliable and fast algorithm to classify different power system faults for various system parameters and fault states.

CHAPTER FOUR

RESULT AND DISCUSSION

4.1 Introduction

The numerical relay is the latest development in the area of power system protection and differs from conventional ones both in design and methods of operation and which derives its characteristics by means of a pre-program series of instructions and calculations (algorithms), based on the selected settings and the measured current or voltage signals. It is based on numerical (digital) devices e.g. microprocessor microcontrollers, Digital Signal Processors (DSPS) etc. This relay acquires sequential samples of the ac quantities in numeric (digital) data form through the Data Acquisition System (DAS), and processes the data numerically using relaying algorithm to calculate the fault discriminants and make trip decisions. In a numerical relay, the analog current and voltage signals monitored through primary transducers (CTs and VTs) are conditioned, sampled at specified instants of time and converted to digital form for numerical manipulation, analysis, display and record in. This processor provides a flexible and very reliable relaying function there by enabling the same basic hardware units to be used for almost any kind of relaying scheme. Thus, a numerical relay has an additional entity, the software, which runs in the background and makes the relay functional Hardware is more or less the in most all the numerical relay. The software used in a numerical relay depends upon the processor used and the type of the relay [4].

4.2 Impedance Detection

The impedance detection based its fault detection on the fact that the input impedance of a transmission line changes when a fault occurs. The magnitude of the impedance varies according to the location of the fault from the relay monitoring it, thus it is called distance relay. Distance relay does not to compare the measurement between two ends of protection zone as in overcurrent relays.

Earlier systems use conventional method for the fault detection which results in the late detection and inaccurate results. Conventional algorithms are based on deterministic computations on a well-defined model for transmission line protection. Conventional distance relays consider power swing as a fault and tripping because of such malfunctioning would lead to serious consequences for power system stability. To improve the performance, numerical relay is used which results in the earlier fault detection.

4.3 The Transmission Line under Study

A 220 KV transmission line system studied as a sample which connects MASHKOR and JEBAL AWLIA (146.7 Km) is studied in this project. This transmission line is used to develop and implement the proposed architectures and algorithms for this problem, and demonstrate the work. The test system is shown in Figure 4.1. In the figure, zone 1 is 30 Km, zone2 is 60 Km, zone3is 90 Km and zone4 is 120Km from the source. More detailed information regarding to the transmission line parameters are presented in the Appendix.

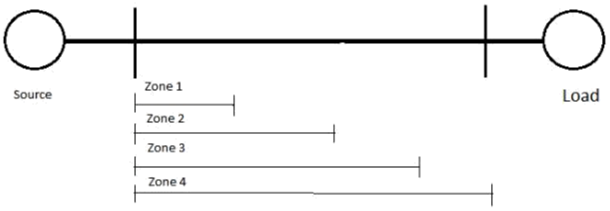


Figure 4.1: A single line diagram of transmission line.

This above single line diagram was modeled by using MATLAB2014a. The line has been modeled using distributed parameters so that it more accurately describes a very long transmission line. The three-phase voltages and currents , and are measured by using V-I measurement. The transmission line is divided into two lines line 1 & line 2 each line is 73.35 Km long. Model of three phase fault simulator is used to simulate various types of fault. In the subsequent simulation results we consider the following four categories, namely

(i) Phase to ground faults.
(ii) Phase to phase faults.
(iii) Double phase to ground faults.
(iv) Three-phase fault

The model of the three phase transmission line is shown in figure (4.2) below:

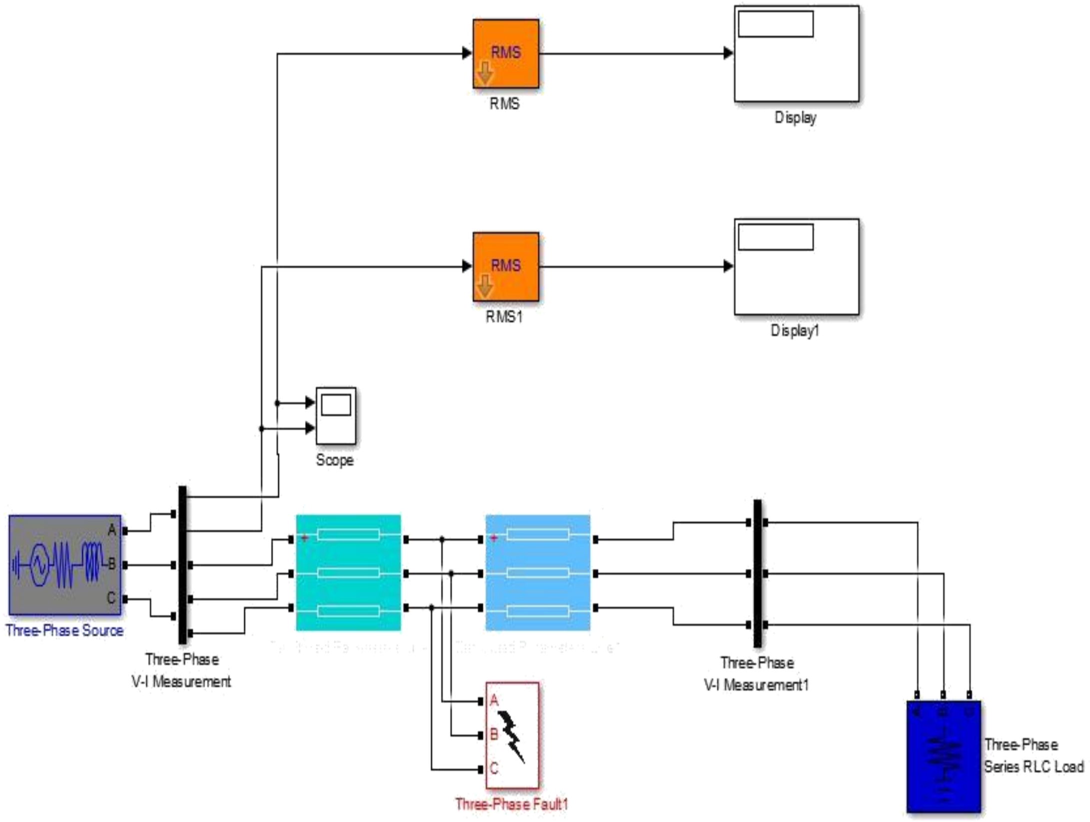


Figure 4.2: Three Phase Test System Model in MATLAB/SIMULINK.

The data set required for numerical relay developed below is generated from various fault situations considering different fault locations by using MATLAB/SIMULINK as shown in details in tables (4.1), (4.2), (4.3), (4.4) and (4.5):

Table 4.1: Voltage and Current results for various fault cases far of 15 Km from the source:

Type of fault	V a (KV)	V b (KV)	V c (KV)	I a (A)	I b (A)	I c (A)
Normal	127.5	127.5	127.5	302.53	302.53	302.53
A-G	56.25	127.2	127.6	13410.7	280	358.7
B-G	127.6	56.25	127.2	358.9	13410.7	280
C-G	127.2	127.6	56.25	280	358.9	1310.7
AB	72.7	71	127.5	14612.9	14322.8	302.6
BC	127.5	72.7	71	302.6	14612.9	14322.8
AC	71	127.5	72.7	14322.8	302.6	14612.9
AB-G	47.5	48	127.3	15704.7	15314.9	330
BC-G	127.3	47.5	48	330	15704.7	15314.9
AC-G	48	127.3	47.5	15314.9	330	15704.7
ABC	38.8	38.8	38.8	16705	16705	16705

From the above values of the Table 4.1, in case of a single line-to-ground fault, the value of the current at faulty phase was a larger than its nominal value and its voltage value was small. In case of line-to-line fault, value of the current at faulty phases were equally and large when comparing to other phase.

The voltage values of the faulty phases were equally in magnitude and take a minimum value.

Table 4.2: Voltage and Current results for various fault cases far of 30 Km from the source:

Type of fault	V a (KV)	V b (KV)	V c (KV)	I a (A)	I b (A)	I c (A)
Normal	127.5	127.5	127.5	302.53	302.53	302.53
A-G	77.9	127.11	127.7	9300.56	289.65	374.15
B-G	127.7	77.9	127.11	374.15	9300.56	289.65
C-G	127.11	127.7	77.9	289.65	374.15	9300.56
AB	82.484	81.36	127.5	11230	10939	302.5
BC	127.5	82.48	81.36	302.5	11230	10939
AC	81.36	127.5	82.48	10939	302.5	11230
AB-G	67.7	68.13	127.4	11845	11487	334.9
BC-G	127.4	67.7	68.13	344.9	11845	11487
AC-G	68.13	127.4	67.7	11487	344.9	11845
ABC	59.4	59.4	59.4	12799	12799	12799

Table 4.3: Voltage and Current results for various fault cases far of 60 Km from the source.

Type of fault	V a (KV)	V b (KV)	V c (KV)	I a (A)	I b (A)	I c (A)
Normal	127.5	127.5	127.5	302.53	302.53	302.53
A-G	96.67	127.03	127.78	5765.9	298.9	387.7
B-G	127.78	96.67	127.03	387.7	5765.9	298.7
C-C	127.3	127.78	96.67	298.9	387.7	5765.9
AB	95.06	94.5	127.5	7693.5	7401.9	302.59
BC	127.5	95.06	94.5	302.59	7693.5	7401.9
AC	127.5	95.06	94.5	7401.09	302.05	7693.5
AB-G	87.26	87.68	127.4	7997	7691	356.6
BC-G	127.4	87.26	87.68	356.6	7997	7691
AC-G	87.68	127.4	87.26	7691	356.6	7997
ABC	80.99	80.99	80.99	8715	8715	8715

Table 4.4: Voltage and Current results for various fault cases far of 90 Km from the source.

Type of fault	V a (KV)	V b (V)	V c (V)	I a (A)	I b (A)	I c (A)
Normal	127.5	127.5	127.5	302.53	302.53	302.53
A-G	105.07	126.99	127.8	4177	303.6	394.12
B-G	127.8	105.07	126.99	394.12	4177	303.6
C-C	126.99	127.8	105.07	303.6	394.12	4177
AB	102.23	102.07	127.5	5861.6	5569.7	302.6
BC	127.5	102.23	102.07	302.6	5861.6	5569.7
AC	102.07	127.5	102.23	5569.7	302.6	5861.6
AB-G	97.02	97.02	127.4	6051	5771	361.87
BC-G	127.4	97.5	97.5	361.87	6051	5771
AC-G	97.5	127.4	79.02	5771	361.87	6051
ABC	92	92	92	6599.6	6599.6	6599.6

Table 4.5: Voltage and Current results for various fault cases far of 120 Km from the source.

Type of fault	V a (KV)	V b (KV)	V c (KV)	I a (A)	I b (A)	I c (A)
Normal	127.5	127.5	127.5	302.53	302.53	302.53
A-G	109.8	126.9	127.8	3273.2	306.5	398.04
B-G	127.8	109.8	126.9	398.04	3273.2	306.5
C-C	126.9	127.8	109.8	306.5	398.04	3273.2
AB	106.9	106.9	127.5	4739	4447	302.6
BC	127.5	106.8	106.9	302.6	4739	4447
AC	106.9	127.5	106.8	4447	302.6	4739
AB-G	102.9	103.5	127.4	4871	4604.9	365.1
BC-G	127.4	102.9	103.5	365.1	4871	4604.9
AC-G	103.5	127.4	102.9	4604.9	365.1	4871
ABC	99	99	99	5303.5	5303.5	5303.5

It was clearly show that the value of the current reduce when the fault occurs far from the source.

The following waveforms show the currents waveform at various cases:

Note that, the measured values that listed in above tables are represented the Vrms value and the value from the plot is a line value.

The current waveform at normal condition on transmission line:

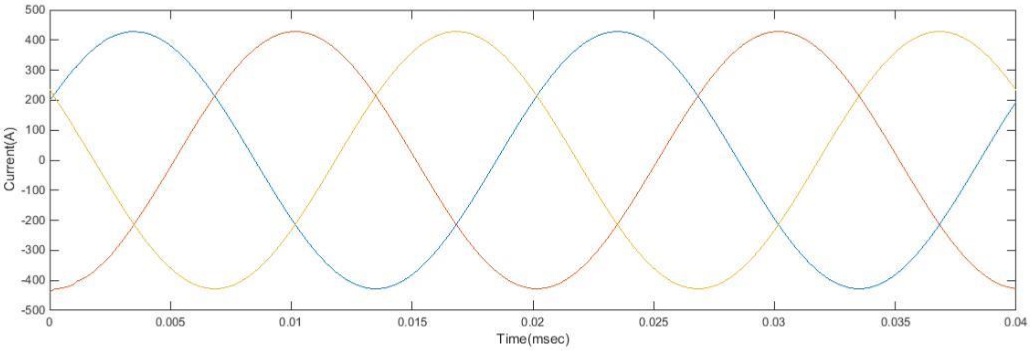


Figure 4.3: Current waveforms at normal condition

As seen from above figure, the value of currents (greater than 400 A) was taken from the scope but the value in the table (302.5 A) describe the momentary value of it.

And at the single line-to-ground fault, the current waveforms are shown below:

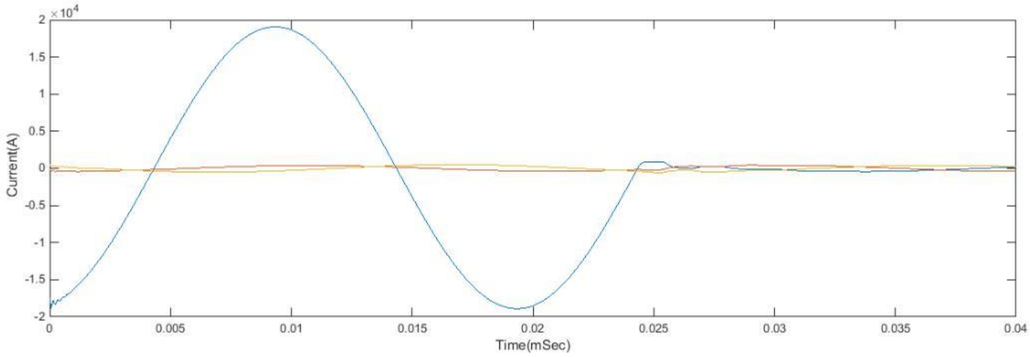


Figure 4.4: Current waveforms at single line-to-ground fault.

From above figure, and when a single line-to-ground fault occurs the value of the current at these phase became greater than of normal condition value. From the scope, the faulty current value is (13410.7A), and its momentary value is greater than (15000 A).

And at the line-to-line fault, the current waveforms are shown below:

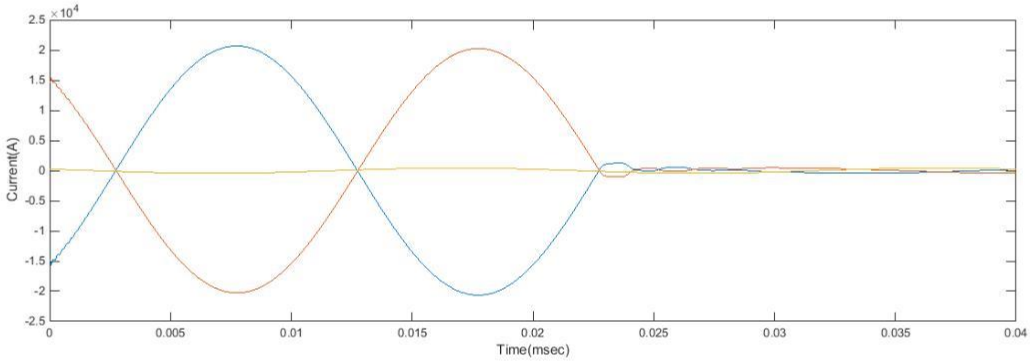


Figure 4.5: Current waveforms at line-to-line fault

And from figure, when double line fault occurs the fault current value was became (14612.9 A), and the momentary value is less than (20000 A).

And at the double line-to-ground fault, the current waveforms are shown below:

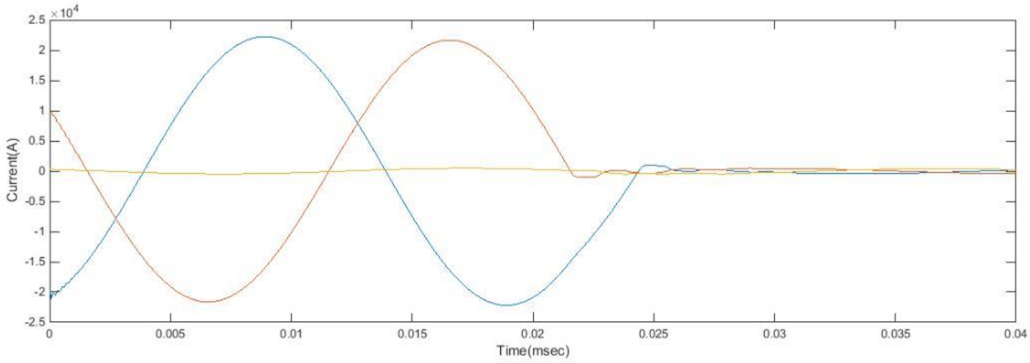


Figure 4.6: Current waveforms at double line-to-ground fault.

From above figure, and when a double line-to-ground fault occurs the value of the faulty current from the scope is (15704.7A), and its momentary value is greater than (20000 A).

And at the double line-to-ground fault, the current waveforms are shown below:

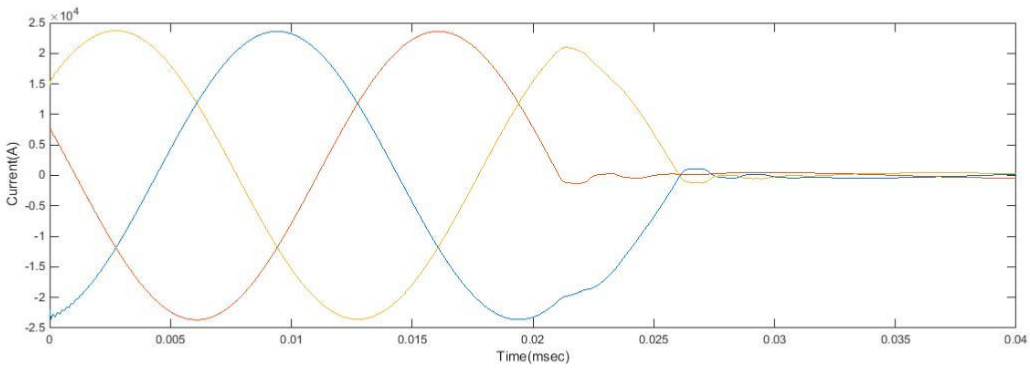


Figure 4.7: Current waveforms at three line fault.

From above figure, when double line-to-ground fault occurs the fault current value was became (16706 A), and the momentary value is less than (25000 A).

4.4 Fault Classification

Once a fault has been detected on the power line, the next step is to identify the type of fault. This section presents an analysis on the fault classification phase using numerical relay

Table 4.5 Fault classifier outputs for various faults.

Type of Fault	A	B	C	G
No Fault	0	0	0	0
A-G Fault	1	0	0	1
B-G Fault	0	1	0	1
C-G Fault	0	0	1	1
A-B Fault	1	1	0	0
B-C Fault	0	1	1	0
A-C Fault	1	0	1	0
A-B-G Fault	1	1	0	1
B-C-G Fault	0	1	1	1
A-C-G Fault	1	0	1	1
A-B-C Fault	1	1	1	0

4.5 Fault Location

Detection of fault location has to be done for the purpose of isolating the faulty section of the system.

The network is expected to identify the location of the fault by classifying the identified fault into one of the three fault zones, namely Zone 1, 2, 3 and 4.

Table 4.6: Isolation numerical relay zone

Fault Location	Z1	Z2	Z3	Z4
Zone 1	1	0	0	0
Zone 2	0	1	0	0
Zone 3	0	0	1	0
Zone 4	0	0	0	1

The data of the zones fed into the numerical relay, and after the classification the performance will be more accurate.

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The project objectives have been achieved where the 220kV Transmission line has been protected by using numerical relays. They are the latest development in the area of protection, which are based on microprocessors. The multi-function numerical relays provide better protection, high reliability, troubleshooting and recording the fault information. Various possible kinds of faults namely single line-ground, line-line, double line-ground and three phase faults have been taken into consideration into this work. MATLAB R2014a has been used along with the Sim Power Systems toolbox in Simulink have been used to simulate the power transmission line model. The grading time in distance relay depend on the fault impedance or the fault location.

5.2 Recommendations:

According to this project and the facts that we had known during the operation in project, we recommend the following point

- Numerical relays must be brought in the protection laboratory in the university instead of or with the electromechanical relays. By using software program loaded the information to the relays.
- As the transmission line which connected between MASHKOR and JEBAL AWLIA is very important line in the national grid, the reliability must be utilized to it.

In the future studies must execute the following recommendations to utilize distance protection by using Artificial Neural Networks

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APPENDIX

Transmission line parameters Data

No.	From	to	Length Km	Type Towers	no.of circuit	conductor type & size	nominal voltage kV	R1Ω/km)	X (Ω m)
55	Mushkur	jebel aulia	146.72		2	2*240mm² ACSR	220	0.067	0.3 2
56	Mushkur	rabak	106.31		2	2*240mm² ACSR	220	0.067	0.3 2
57	Rank	roseires	172.54		2	2*240mm² ACSR	220	0.067	0.3 2
58	Rabak	rank	163.46		2	2*240mm² ACSR	220	0.067	0.3 2
59	Rabak	tandalti	112.26		2	2*240mm² ACSR	220	0.067	0.3 2